Investigation of the Opportunity for Small-Scale Geothermal Power Plants in the Western United States

K. Gawlik
C. Kutscher
National Renewable Energy Laboratory
Golden, CO

March 13, 2000

DRAFT

This report has not yet received editorial or peer review in accordance with NREL publications policy.

Investigation of the Opportunity
for Small-Scale Geothermal Power Plants
in the Western United States

K. Gawlik
C. Kutscher
NREL
March 13, 2000

Summary

NREL staff selected the most promising geothermal sites from the Geo-Heat Center's 271-site survey of geothermal resources in Western states. For each of these, we ran NREL's Cycle Analysis Software Tool (CAST) to analyze the performance of a binary-cycle geothermal power plant operated in each of two modes: directly using the geothermal fluid resource and using it in series with a direct-use application. Plant costs were modeled as a function of plant size using data from the Next-Generation Geothermal Power Plant (NGGPP) study and reports by R. DiPippo and D. Entingh (who used cost data provided by Barber-Nichols). (We also show cost results based on a simple flat-rate assumption of $2,400/kW suggested by ORMAT, which tends to give lower costs.)

Tables 1a and 1b summarize the results for the sites studied. Table 1a presents results for plants that make complete use of the geothermal fluid enthalpy and have no direct use downstream of the plant. These plants are called "standalone," but this would also represent the case of a direct use with its own brine supply being collocated with the power plant Table 1b presents results for the configuration in which there is a direct use downstream of the plant. This arrangement is known as a "series" flow. In this scheme, there is a 40°F temperature drop limitation imposed on the geothermal fluid through the plant. (This number, taken as a typical temperature drop for series operation, was established by DOE as the design assumption to be used in this study.) Neglecting the small series option at Bridge, Idaho (100 kW) and the small plants at Government Camp, Oregon, plant sizes range from 249 kW to 1 MW (the upper limit imposed on this study). Total plant-only capital costs range from $566,000 to $3.4 million, and plant and field capital costs ranged from $1.4 million to $5 million (the upper limit imposed on this study). Costs are much higher when exploration and well costs are included. These costs do not include taxes or injection wells. Costs of electricity, assuming an 80%, or $4 million (whichever is lower) DOE cost share of plant capital costs as well as exploration and well drilling and testing costs, fall under 5 cents per kWh for more than half the plants. This compares to local electricity rates that are mostly in the range of 3 to 6 cents per kWh.

Costs of electricity are fairly high because economies of scale work against small plants. This is especially true when exploration and drilling costs are necessary. These essentially fixed costs have a major impact on electricity costs for small plants. While it had been hoped in the early stages of this study that there might be existing wells available that would obviate exploration and

drilling costs, it appears that this is not typically the case. And where existing wells are being used for direct-use applications, it is unlikely that extra geothermal fluid energy is available for power plant use. Thus, in the real marketplace, economic justification for most of these plants would probably require combining the economics of the power plant with a new direct-use application. As shown later in this report, the economic picture improves somewhat if we use a simple flat-rate cost assumption of $2,400/kW for the power plant, as suggested by ORMAT. However, we chose to base our main results on the cost model used by Entingh because it is based on more detailed information and is more conservative.

In order to provide a more realistic and practical picture, most of the results in this report are presented for specific sites. However, we have also produced generic cost results applicable to any site, and these are reported in Section 4.

Table 1a. Summary of Total Capital Costs and Cost of Electricity for the Stand-Alone Plant. (COE assumes 80% cost share of plant, exploration, and well field costs.)

Location	T (°F)	Plant Size (kW)	Capital Costs: Plant	Capital Costs: Field	COE (¢/kWh): No cost sharing	COE (¢/kWh): Full cost sharing
Beryl, UT	748	748	$1,844,864	$2,617,246	10.48	4.72
Newcastle, UT	207	645	$2,165,882	$527,173	13.96	6.25
Bluffdale, UT	185	297	$1,187,632	$544,642	88.85	39.34
Marysville, MT	206	395	$1,405,220	$2,408,644	33.59	15.11
San Simon, AZ	273	1000	$2,572,071	$2,353,250	9.22	4.15
Cotton City, NM	225	915	$2,768,322	$518,174	8.93	4.00
Govt. Camp, OR	250	109	$383,550	$974,173	25.06	11.01
Vale, OR	239	635	$1,908,873	$340,200	7.68	3.42
Lakeview, OR	235	1000	$2,894,311	$549,252	7.70	3.45
Klamath Falls, OR	221	1000	$3,037,751	$790,918	9.90	4.43
New Pine Creek, OR	192	1000	$3,393,606	$1,203,900	30.97	13.87
Breitenbush Hot Spg, OR	192	283	$1,106,169	$597,876	40.13	17.76
Union, OR	185	439	$1,681,277	$944,397	91.47	40.72
Star, ID	346	944	$2,027,665	$2,966,903	9.04	4.08
Bridge, ID	295	271	$757,232	$628,721	8.90	3.91
Swan Valley, ID	284	613	$1,614,952	$3,385,048	14.83	6.69
Pyramid Lake, NV	260	1000	$2,672,819	$1,070,953	7.29	3.27

Table 1b. Summary of Total Capital Costs and Cost of Electricity for the Series Configuration. (COE assumes 80% cost share of plant, exploration, and well field costs.)

Location	T (°F)	Plant Size (kW)	Capital Costs: Plant	Capital Costs: Field	COE (¢/kWh): No cost sharing	Fully cost shared COE: Plant & Field	Fully cost shared COE: No field expense
Beryl, UT	300	264	$594,591	$2,617,244	18.74	8.41	1.60
Newcastle, UT	207	516	$1,537,623	$527,173	6.11	2.72	2.12
Bluffdale, UT	185	274	$1,020,817	$544,642	8.66	3.82	2.64
Marysville, MT	206	323	$1,067,144	$2,408,644	16.57	7.45	2.35
San Simon, AZ	273	567	$1,242,184	$2,369,770	9.82	4.41	1.56
Cotton City, NM	225	634	$1,754,363	$508,661	5.46	2.44	1.96
Govt. Camp, OR	250	58	$189,238	$974,173	30.19	13.17	2.32
Vale, OR	239	379	$1,038,260	$340,200	5.50	2.42	1.94
Lakeview, OR	235	690	$1,767,396	$560,101	5.17	2.31	1.82
Klamath Falls, OR	221	607	$1,703,625	$606,387	5.80	2.58	1.99
New Pine Creek, OR	192	1000	$3,157,533	$1,309,323	6.86	3.07	2.24
Breitenbush Hot Spg, OR	192	264	$965,287	$597,876	9.01	3.98	2.60
Union, OR	185	406	$1,445,125	$944,397	8.99	3.99	2.53
Star, ID	346	309	$602,737	$2,954,924	17.76	7.98	1.39
Bridge, ID	295	100	$249,348	$628,721	13.10	5.63	1.78
Swan Valley, ID	284	249	$566,174	$3,383,104	24.48	11.02	1.62
Pyramid Lake, NV	260	516	$1,235,288	$1,063,415	6.83	3.04	1.70

1.0 Background and Introduction

Small-scale geothermal power plants have a history of proven performance. A study by PERI[1] of small-scale geothermal power plants for remote applications cited a number of advantages of these systems. Modular designs are easily transportable and allow a plant to be built for a small up-front cost. They can also be automated so that they do not require a full-time operator. (In fact, the 600 kWe Wineagle plant, built in Susanville, California by Barber-Nichols is completely automated to the extent that it can automatically restart itself after a shutdown.) According to Lund[2], there are 50 geothermal power plants in the world at or below 5 MWe. U.S. small-scale plants are all located in California and Nevada, with the exception of the 4.8 MWe Cove Fort plant in Sulphurdale, Utah.

The type of power plant preferred depends on the resource temperature. Typically, for resource temperatures above about 300°F (150°C), flash steam plants are the most cost-effective. Below this temperature, binary-cycle units are usually used. A list of the U.S. plants under 5 MWe in size is given in Table 2. These are all binary-cycle designs.

Table 2. Existing Small-Scale Geothermal Power Plants in the U.S.[3]

Plant	Location	Net Power	Temp. (°F)	Flow (lb/hr)	Manufacturer
Amedee	Wendel, CA	1.5 MWe	219	1,594,000 (max.)	Barber-Nichols
Wineagle	Wendel, CA	600 kWe	230	498,000	Barber-Nichols
TAD's Ent.	Wabuska, NV	1.5 MWe	220	896,400	ORMAT
Empire	Empire, NV	3.6 MWe	237	NA	ORMAT
Cove Fort	Sulphurdale, UT	3.2 MWe	280	200,000	ORMAT
Soda Lake #1	Fallon, NV	2.7 MWe	370	400,000	ORMAT

---

[1]Entingh, Daniel, Easwaran, Eyob, and McLarty, Lynn, "Small Geothermal Electric Systems for Remote Powering," *GRC Transactions*, Vol. 18, October 1994.

[2]Lund, John W., and Boyd, Tonya, "Small Geothermal Power Project Examples," *GHC Bulletin*, Vol. 20, No. 2, June 1999.

[3]Lund, ibid. The source document does not describe maximum and average flowrates for each resource. Where the flowrate is said to be the maximum, it is so indicated in the table. Otherwise, the flowrate is taken as an average value.

A study of 271 geothermal sites in the Western United States by the Oregon Institute of Technology's Geo-Heat Center revealed that many of these would be suitable for electric power generation or direct use. The U.S. Department of Energy is interested in taking advantage of these resources. The purpose of this study is to evaluate the cost and potential for using the most promising of these sites for small-scale geothermal power plants.

In addition, there are high temperature resources in the Aleutian Islands, and in locations in the Western US that are not included in the 271-site study because they are not near a community. In Alaska for instance, high temperature resources exist close to large industrial users such as canneries, and those resources should be considered for small scale geothermal plants. However, due to lack of information at the time this study was conducted, they were not included.

2.0 Analysis

2.1 Overview

The size range considered for this study is from approximately 300 kWe to 1 MWe. Plants smaller than 300 kWe tend to be very expensive on a per kilowatt basis because of the loss of economies of scale. Plants larger than 1 MWe are likely to be too high in capital cost to fulfill the DOE goal of deploying a number of new projects in the field. The cost of a plant depends strongly on the temperature and flow rate of the resource, however, so we have included plant sizes outside this range in cases where their costs appear attractive.

Because exploration and well costs become a very high fraction of total plant cost for small plants, it is highly advantageous to seek applications at existing wells. We reviewed all of the 271 Western geothermal sites compiled by the Geo-Heat Center and selected those with a favorable combination of resource temperature and flow rate. Figure 1 (Nichols[4]) shows roughly how the net output of a plant depends on both of these quantities. This shows, for example, that a site with low resource temperature but a high wellhead flow rate might be superior to one with a higher temperature but a lower available flow.

We also sought information on Alaska. It was not included in the 271 site study, but information on its current uses is available from the Geo-Heat Center[5]. The state map shows a region of high temperature where geothermal development could occur, but no current electric power applications. The current uses are heating and resorts, with resource temperatures well below 200°F. Pilgrim Hot Springs, Manley Hot Springs, and Chena Hot Springs are said to have temperatures over 212°F. Sites along the Aleutian chain also are said to have temperatures of

---

[4]Nichols, K.E., "Wellhead Power Plants and Operating Experience at Wendel Hot Springs," *GRC Transactions,* Vol. 10, pp. 341-346, 1986.

[5]Geo-Heat Center, Oregon Institute of Technology, Klamath Falls, Oregon, http://www.oit.edu/other/geoheat/state/ak/ak.htm.

284°F[6]. No additional information, such as resource depth, permeability, or extent, was available at the time of this study.

Sites outside of the 271-site study should not be excluded from consideration. There are a number of resources that are attractive for small-scale geothermal development and that are not located near a population center. However, documented information on those site characteristics was not available at the time of this study.

In many cases, the resource information in the 271-site study describes wells that are no longer viable. For instance, some of the data are from exploratory oil and gas wells drilled 60 years ago, and the wells are probably long since plugged and abandoned. It is likely that the development of a resource at these sites with only abandoned wells would require significant exploration, drilling, and testing to characterize the geothermal resource and construct a useful well field.

The 271-site study appears to have incorrect information on the Cotton City resource. The study lists resource flow as 200 gpm, but in another part of the Geo-Heat Center web site, the flow for a direct use in that region is given as 2000 gpm. Since this 32-acre greenhouse installation is the largest in the nation, the 2000 gpm value was used.

For locations where an existing direct use is established, it is not likely that one would be able to insert a retrofitted power plant upstream of the direct use (even with a limited temperature drop of the geothermal fluid, such as the 40°F drop we assumed for series operation) and still obtain the same benefit from the geothermal fluid in the direct use application. For example, in Newcastle, Utah, the primary direct use is a 1,000,000 square foot greenhouse with access to geothermal fluid at approximately 200°F. The heating system is designed to use geothermal fluid at this temperature, and a geothermal fluid temperature 40°F lower would not provide adequate heating of the greenhouse. It has been estimated that the direct use would have to add 30% to 40% more equipment to compensate for the low entering temperature[7]. Simply increasing the flowrate is probably not an option because resource flow may already be completely utilized, and pump and motor sizes, and heat exchanger sizes are based on a particular, existing application.

A parallel system with part of the well flow diverted to the power plant, which can fully utilize the geothermal fluid enthalpy, may also not be feasible in a simple retrofit design. An operator of a direct use application would probably initially develop his resource to provide only as much geothermal fluid as he needs, with little left over for other uses. He may also size his direct use to use the geothermal fluid flow that is available from the resource. However, if he does have a resource and pumping capability that can supply more geothermal fluid than he needs, then a retrofit design such as this may work well.

[6]Lund, John, private communication.

[7]Lund, John, and Rafferty, Kevin, private communication.

It is likely that the best way to build a power plant collocated with a direct use application is to design the entire system, including well field, from scratch. Exploration and resource development would be a necessary first step. Next, the type of direct use, the economics of the product, the thermal and electrical power draws of the direct use, and the market for any excess power would have to be evaluated to determine whether a series or stand-alone design would be appropriate, and to optimize the entire system including direct use.

2.2 Well Characteristics and Costs

For the purposes of this study, assumptions have been made about the characteristics of the well field that would support a power plant and direct use application. Although the 271-site study reports well flows for each site, these were not power production wells and the well sizes were not given. Many of these wells are no longer available. With information from Mike Prairie of Sandia[8], assumptions were made about the typical flowrates from 12", 6", and 4" diameter wells in which resource permeability is high. For a 12" well, the flowrate was 715,000 lb/hr; for a 6" well, 185,000 lb/hr; and for a 4" well, 85,000 lb/hr. Each site, given an anticipated flowrate from the resource, would have a combination of wells of the same or different sizes. For a given well depth, the cost per foot of drilling wells decreases with hole size; however, the flowrate from the well goes down much faster with decrease in diameter than the cost per foot does. For each case the various combinations of well sizes were considered to determine the minimum cost to obtain the anticipated flowrate, with consideration given to the impracticality of having numerous well sizes at each site. Since permeability and well drawdown information are not available, the assumption was made that 1 kW of power could pump 2050 lb/hr of geothermal fluid. This is based on data for typical wells for the baseline binary plants in the NGGPP report[9] and may be considered conservative.

Most of the resource flows are from the 271-site study. These flows are based on a collection of wells at the site, which may be widely separated. Since a number of these wells may be plugged and abandoned now, and resource development is probably necessary for the development of new small scale systems, these resource flows are taken as indicative of what may be available with new wells. The actual resource flows that will be available will only come out of a program to explore and test resources that are not currently in use.

The information on the Nevada resource is anecdotal and is not supported through documentation. Better information may become available at a later date.

---

[8]Prairie, Mike, "Development Scenario for a Small Geothermal Power Plant," provided to NREL in support of this study, January 2000.

[9]CE Holt Co., *Next Generation Geothermal Power Plants*, EPRI, February 1996.

Well costs are based on Mike Prairie[10] and John Finger's work on drilling through soft and hard material. A value of cost per foot was found from averaging the value for these two materials, since it is possible that a variety of materials may be encountered in drilling. The cost-per-foot values were for wells up to 700 feet. When wells are drilled to thousands-of-feet depth, cost-per-foot values typically drop due to the fixed costs of drilling being distributed over greater depths. This reduction in cost per foot was not taken into account, so well costs on a per-foot basis will tend to be conservative in this study. Cost-per-foot values tend to rise when depths are on the order of tens of thousands of feet, but only a few sites in this study have resources at those depths. In contrast, Entingh's[11] paper described cost-per-foot values that rose with well depth. Well depths are assumed to be the depths reported in the OIT study. These depths may be much greater than necessary for geothermal development. The wells may now be plugged and abandoned, so new wells will probably have to be drilled to unknown depths. No injection wells were budgeted in this study since a number of small-scale systems (Wineagle, Amedee, and Wabuska) use surface disposal. If an injection well is needed, that would of course add to the cost. However, injection wells are typically lower in cost than production wells.

2.3 Plant Optimization

Because most of the resource temperatures are near or below 300°F, we assumed a simple binary-cycle system consisting of a feed pump, preheater/evaporator, turbine/generator, and air-cooled condenser, as shown in Figure 2. Analysis was done using NREL's Cycle Analysis Software Tool (CAST) (Gawlik and Hassani[12]). CAST sizes plant components and estimates plant performance using established typical heat transfer coefficients in the heat exchangers and typical efficiencies of the turbine, gearbox, generator, and feed pump from the Next Generation Geothermal Power Plant (NGGPP) study. Comparisons between CAST results and the NGGPP base case results for large plants show good agreement. The program performs enthalpy balances around a closed loop using NIST thermodynamic property data. It can analyze various fluid choices and allow selection of the best fluid for each resource.

CAST uses a relative cost analysis to compare different plant designs to a baseline design. Detailed cost data from Barber-Nichols, based on facilities of 3 and 7 MWe in size, was made available to NREL in 1994. CAST is given a range of values for significant plant parameters, such as heater pinch temperature difference, heater working fluid pressure, and condenser bubble point temperature, and then sizes the components to obtain a plant that will function under each particular combination of parameter values. For this plant, a relative COE is then estimated based on how the component sizes differ from the base case. The best plant design is chosen as the one

---

[10]Prairie, ibid.

[11]Entingh, ibid.

[12]Gawlik, K., Hassani, V., "Modeling and Analysis of Advanced Binary Cycles," NREL, Golden, CO, 1997.

with the lowest estimated relative COE. CAST thus determines the best plant for each resource, the effectiveness and thermal efficiency of the best plant, and the best working fluid.

2.4 Actual Plant Cost Estimation

The actual COE of a plant depends on plant size because of economies of scale. CAST does not account for plant size, and the Barber-Nichols detailed cost data cannot be readily extrapolated down to plant sizes in the hundreds of kilowatts. For large plants, turbine-generator sets may be scaled according to plant size, and a power law relationship between plant size and cost can be developed. When we attempted to use such a power law to extrapolate the costs downward, we obtained costs much higher than those reported for actual small plants. This may be because small-scale plants depend on more modularity than that used in a large plant. For instance, multiple small systems may be grouped to produce a plant of higher output. In this scenario, economies of scale in individual components are not realized, but there will be economies related to the purchase of a number of the same components. ORMAT tends to use this design philosophy to build all their plants, and this approach has advantages with respect to maintaining high plant output while modules are being serviced. Thus, extrapolating data for a multi-MW plant down to the hundreds-of-kW level is risky.

The best data available on small plant capital and O&M costs appears to also be from Barber-Nichols and was provided to Dan Entingh in 1993. This data was not detailed like the data provided for the 3 and 7 MWe plants, and so could not be used by CAST to optimize designs. However, it was developed specifically for the study of small-scale, remote power applications and so can be used to develop absolute COE values. It scales plant costs as a function of plant size and resource temperature. O&M is a function of plant size. In our study, this cost information, updated with inflation rate data over the last six years, was used to develop the actual COE values and screen the plant designs developed for resources in the 271-site study to determine the most likely candidates for plants collocated with existing applications.

This Barber-Nichols small-scale plant cost data assumed the plants were mass produced, so it was necessary to make an adjustment for our case. We did this by normalizing the Entingh cost-size correlation so that it would provide a total cost for a 600 kWe plant that agrees with the inflation-adjusted cost for the 600 kWe Wineagle plant.

The Barber-Nichols small-scale plant cost data are for plants that completely utilize the resource; that is, plants that do not have a temperature limit on the outlet geothermal fluid. If a plant does have a temperature limitation, such as the 40°F maximum temperature drop imposed on plants in the series configuration, then its thermal efficiency will be higher than a plant that does not have this limitation (such as the stand-alone plant). The higher thermal efficiency is due to the higher average geothermal fluid temperature in the vaporizer, all else being equal. Because of this higher efficiency, less capital investment is required for a given net plant output. Therefore, a correction is applied to the small-scale Barber-Nichols cost data to reflect this anticipated reduction in cost. The correction is the ratio of the stand-alone efficiency value to the series efficiency value.

Given the best plant geothermal fluid effectiveness and resource characteristics, one can obtain COE from the Barber-Nichols small-scale plant capital and O&M data, and estimates of the cost to develop the resource. Geothermal fluid effectiveness and the type of access the plant has to the resource determine plant size. Plant size and field capital cost are then used to determine total capital cost and annual O&M cost (taken as 4% of total capital cost, not including exploration and well testing costs). These total and annual costs, with the assumption of typical nominal and real discount rates and a 20-year usable lifetime of the power plant, were used to determine total life-cycle cost of the plant. Typical capacity factors for grid-connected plants were then used in the determination of the cost of electricity from the plant. The resource development costs were based on fixed exploration and test costs, described later, and a drilling cost for conventional wells to the depth reported in the OIT study. The number of wells required at the resource is the minimum necessary to deliver the reported flow at the resource, given a typical flow of a single production well.

A maximum capital cost of $5 million was applied to the sum of plant and resource development capital costs. To limit the combined capital cost to a maximum of $5 million, the plant size was reduced, and the number (and sizes, in some cases) of wells was reduced until the total capital cost was no more than the limit. The stand-alone and series configurations were handled independently, so the number and type of wells could be different between them.

2.5 Site Characteristics

The sites considered in this study are shown in the map (Figure 3). Sites were initially selected based on their location in places where geothermal power does not currently have a large presence, and where establishment of a collocated facility would be most feasible.

A list of sites is presented in Table 3 below. Sites with a combination of high temperature and high available flow rates are the most attractive, because they offer reasonably high thermodynamic efficiencies and large available power. Sites with high temperatures but extremely low flowrates (on the order of tens of gallons per minute) were not considered because the available thermal power is quite low. Sites with moderately low temperatures, but high flowrates were considered for further study; however, these sites suffer from high parasitic pumping power requirements. The flowrates are limited in cases where the maximum plant size of 1 MW has been reached, thus the flowrates for stand-alone and series options may be different. Where actual resource conditions show that a higher flow may be available, then additional power plant modules may be installed, or direct uses may be considered to use the extra fluid. The minimum flowrate, in cases where a flowrate was not available in the 271-site study and a 1 MW size limit was not reached, was assumed to be 450,000 lb/hr[13].

---

[13]This is the average of the production well flow rates at the existing small-scale power plants for which data on the number of wells and well flowrates are available (Amedee, Wineagle, Wabuska, Empire, and Cove Fort).

Table 3. Resource Site Characteristics

Location	Temp. (°F)	Flow (lb/hr) Stand-alone	Series	From 271 study: Well depth (ft)
Beryl, UT	300	180,559	301,022	12297
Newcastle, UT	207	750,000	750,000	499
Bluffdale, UT	185	547,800	547,800	738
Marysville, MT	206	450,000	450,000	6791
San Simon, AZ	273	358,295	450,000	6667
Cotton City, NM	225	781,250	996,000	440
Govt. Camp, OR	250	54,780	54,780	4678
Vale, OR	239	383,500	383,500	266
Lakeview, OR	235	639,795	860,000	604
Klamath Falls, OR	221	831,255	1,177,856	656
New Pine Creek, OR	192	1,582,278	1,700,680	558
Breitenbush Hot Spg, OR	192	448,200	448,200	1017
Union, OR	185	810,000	810,000	1000
Star, ID	346	184,953	450,000	14010
Bridge, ID	295	71,200	71,200	2700
Swan Valley, ID	284	188,806	450,000	16178
Pyramid Lake, NV	260	428,289	450,000	2500

Much of the available resource information is unfortunately dated, and the wells may no longer be available for use. This information is only usable for initial assumptions about what may be obtained at a site, and the actual resource conditions will have to be determined through exploration and testing. The sites in this study include regions where further development may be impractical. These sites are included for comparison purposes only and are probably not good candidates for small scale development. As an example, Klamath Falls is already using its resource heavily for district heating, and the installation of a power plant would detrimentally affect the current use and also confront considerable restrictions with respect to local industrial zoning[14].

At sites where the geothermal fluid is being used for process heat, we have two alternatives for power generation: 1) series use in which all of the geothermal fluid is first used to generate electricity with the exit geothermal fluid going on to the process and 2) stand-alone use in which the geothermal fluid is diverted from the process and used only for electricity generation. In the first case, we assumed that the geothermal fluid could drop in temperature only 40°F to still allow sufficient heat content for the process. In the second case, no lower limit was set on the geothermal fluid. The CAST results were put into a Microsoft Excel spreadsheet that allows one

[14]Rafferty, Kevin, Geo-Heat Center, Oregon Institute of Technology, private communication.

to select the percent of total geothermal fluid flow rate diverted for power production in the stand-alone operation mode.

2.6 Determination of Cost of Electricity

At low-temperature resources, the plant geothermal fluid effectiveness is low, and a high geothermal fluid flowrate is required for a reasonable plant output. This can result in significant pumping power, which reduces the net power plant output. If the resource is already being pumped for a direct use application, and the power plant can use that geothermal fluid in series, then the additional pumping power for the electric power generation will be relatively low, and the net power output of the plant is not greatly affected. However, if the power plant is the only use of the geothermal fluid, at least initially, then the economics of the facility will be significantly affected by the pumping power requirement. COEs for these two scenarios are presented in the results. For the low-temperature resources, the COE is much more affected by pumping power than at the high-temperature resources.

The manner in which capital cost sharing is provided makes a large difference in COE. The cost sharing may be applied to the power plant module alone, or it may apply both to the power plant module and the exploration, drilling, testing, and development of the resource. In either case, the assumption is made that cost sharing only applies to capital costs, and annual O&M is entirely paid for by the owner. Results are presented for both cost-sharing methods. The DOE cost share is assumed to be 80% of the capital cost, or $4,000,000 (the assumed upper limit on available DOE funds), whichever is lower.

Assumptions related to total life-cycle costing and final COE calculation were a 20-year plant life, 10% nominal discount rate and 3% inflation rate. The real discount rate was 6.8%. This interest rate was used, yielding a constant dollar analysis. The inflation rate was compared to producer price indices (PPI) and a large difference was not found. The PPI for general industrial machinery and equipment between 1986 and 1999 was found to be 2.9%. The PPI for engineering design, analysis, and consulting services was found to be 2.8%, and the PPI for turbine generator sets was found to be 2.5%[15]. As in the Entingh study, no taxes were considered[16]. The capacity factor was 90%. This factor is conservative when compared to the performance of Wineagle, which has a reported capacity factor of 109%[17]. O&M costs are assumed to be 4% of capital costs that include power plant module and resource development, but exclude exploration and testing.

---

[15]Bureau of Labor Statistics, http://stats.bls.gov/, data extracted on Dec. 2, 1999.

[16]How depreciation of the facility is handled has a significant effect on the tax calculation. At the time of this study, it was not known if the owner could depreciate the entire value of the facility, or only the fraction not cost-shared. The method of depreciation was also unknown.

[17]Lund, ibid.

The COE was determined from the following standard financial formulae:

$$COE = \frac{TLCC * UCRF}{Q}$$

where TLCC is the present value total life cycle cost of plant and field expenses:

$$TLCC = \left[TCC + OM(PC + FC)\frac{P}{A} \right](1 - ITC)$$

where TCC is the total capital cost including plant capital, resource exploration, well drilling and testing, geothermal fluid pumps and gathering system, and siting and licensing; OM, the percent of capital cost for determining annual operating and maintenance expenses, assumed to be 4%; PC, plant capital; FC, field capital, which for O&M purposes is made up of well drilling cost (to include future well rework) and the geothermal pumps and gathering system; ITC, investment tax credit of value 0.1; and where the equal series present worth discount factor, P/A, is defined by

$$\frac{P}{A} = \frac{(1+i)^n - 1}{i}$$

with i equal to 6.8% and n, 20 years. Q is the total energy produced during the twenty years of operation, and it may be adjusted according to whether pump power is considered. Field capital also may be excluded from the TLCC calculation if the field is already developed and the pumps and gathering system are installed or attributed to a direct use. The uniform capital recovery factor is defined by

$$UCRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

with i and n as defined above.

Local electricity prices were obtained for each location. In many areas where geothermal development is possible, there are abundant hydro and coal resources, and the low price of electricity reflects this. The electricity price is based on an industrial user who is in the pricing bracket that consists of a consumption of hundreds of kilowatts on average, with a peak demand of twice the average. In most areas, this was sufficient information to find the right bracket, since the pricing ranges were very broad in terms of consumption. The determination of the unit energy price is based on monthly fees, demand charges, and energy charges. The calculation was made for a month's worth of usage and normalized with respect to energy used. In some cases, different winter and summer rates were found to be used by the local supplier, so a calculation was made for the entire year and normalized.

While the local electricity supplier probably provides power to current established direct uses, excess power from a geothermal power plant may not have to be sold to the local supplier. For instance, one greenhouse owner who would like to install a power plant has identified customers in major cities in other states who would pay more for his excess power than the local Rural Electric Association (REA) or Co-op. Thus, one may be able to obtain a better price for excess power than the local price.

3.0 Results

3.1 Plant Performance

The performance of the plants is shown in Table 4. The geothermal fluid effectiveness (net plant power divided by the geothermal fluid mass flow rate) and thermal efficiencies were calculated by CAST for isobutane and isopentane plants. The cycles are conventional Rankine with no recuperation. The “no temperature limit” column is for the case where the plant has full utilization of the geothermal fluid; that is, the stand-alone configuration. The series configuration's performance is represented by the “40°F drop” column. In the Fluid column, iC4 refers to isobutane, and iC5 refers to isopentane.

Table 4. Results for Plant Geothermal Fluid Effectiveness and Efficiency

Location	Effect., no T limit	Fluid	0_{net}	Effect., 40°F drop	Fluid	0_{net}
Beryl, UT	4.04	iC4	9.7%	1.43	iC5	11.9%
Newcastle, UT	0.90	iC4	5.6%	0.72	iC4	6.4%
Bluffdale, UT	0.54	iC4	4.3%	0.50	iC4	4.6%
Marysville, MT	0.88	iC4	5.5%	0.72	iC4	6.1%
San Simon, AZ	2.79	iC4	8.5%	1.26	iC5	10.6%
Cotton City, NM	1.28	iC4	6.6%	0.89	iC4	7.5%
Govt. Camp, OR	1.98	iC4	7.7%	1.06	iC4	9.0%
Vale, OR	1.66	iC4	7.2%	0.99	iC4	8.4%
Lakeview, OR	1.56	iC4	6.9%	0.97	iC4	8.2%
Klamath Falls, OR	1.20	iC4	6.3%	0.85	iC4	7.2%
New Pine Creek, OR	0.63	iC4	4.7%	0.59	iC4	5.0%
Breitenbush Hot Spg, OR	0.63	iC4	4.7%	0.59	iC4	5.0%
Union, OR	0.54	iC4	4.3%	0.50	iC4	4.6%
Star, ID	5.10	iC5	11.1%	1.69	C5	13.8%
Bridge, ID	3.80	iC4	9.4%	1.40	iC5	11.7%
Swan Valley, ID	3.25	iC4	9.0%	1.36	iC5	11.5%
Pyramid Lake, NV	2.33	iC4	8.0%	1.15	iC4	9.7%

3.2 Cost Results Based on Barber-Nichols Data

If there is no capital cost cap, and the resource is entirely available to the power plant module in either the stand-alone or series configuration, then the plant sizes and plant capital costs are as shown in the Table 5 below.

Table 5. Plant Capital Cost Results

	Plant Size (kW)		Plant Capital Cost	
Location	**Stand-alone**	**Series**	**Stand-alone**	**Series**
Beryl, UT	748	264	$1,844,864	$594,591
Newcastle, UT	645	516	$2,165,882	$1,537,623
Bluffdale, UT	297	274	$1,187,632	$1,020,817
Marysville, MT	395	323	$1,405,220	$1,067,144
San Simon, AZ	1000	567	$2,572,071	$1,242,184
Cotton City, NM	915	634	$2,768,322	$1,754,363
Govt. Camp, OR	109	58	$383,550	$189,238
Vale, OR	635	379	$1,908,873	$1,038,260
Lakeview, OR	1000	690	$2,894,311	$1,767,396
Klamath Falls, OR	1000	607	$3,037,751	$1,703,625
New Pine Creek, OR	1000	1000	$3,393,606	$3,157,533
Breitenbush Hot Spg, OR	283	264	$1,106,169	$965,287
Union, OR	439	406	$1,681,277	$1,445,125
Star, ID	944	309	$2,027,665	$602,737
Bridge, ID	271	100	$757,232	$249,348
Swan Valley, ID	613	249	$1,614,952	$566,174
Pyramid Lake, NV	1000	516	$2,672,819	$1,235,288

Expenses related to the development of the resource and to the load on the power plant to pump the geothermal fluid are presented Tables 6a and 6b. The exploration cost was estimated to be the same for all resources[18]. Well testing costs depend on the number of production wells. The cost of the geothermal fluid pumps and gathering system is assumed to be 34.4¢/(lb/hr of geothermal fluid). This is an average of the costs for binary plants described in the NGGPP report[19]. Siting and licensing is assumed to be $65/kW[20] or $50,000, whichever is higher. This cost does not take into account the costs of environmental impact statements or licensing from the

[18]Renner, Joel, "Exploration and Well Testing Costs for Small to Medium Size Geothermal Plant," and accompanying email message, supplied to NREL in support of this study, January 2000.

[19]CE Holt Co., ibid.

[20]CE Holt Co., ibid.

federal government. The highest well costs are for resources with deep wells. The resources may not actually need to have wells this deep if new wells are drilled. For the low-temperature plants, almost all the power plant output is necessary to run the geothermal fluid pumps.

Table 6a. Costs and Pumping Power Associated with Well Field for the Stand-alone Configuration

Location	Explor. cost	Well cost	Well test & review	Pumps and Gathering system	Siting and Licensing	Pump Pwr (kW)	Fraction of Plant net
Beryl, UT	$45,000	$2,428,658	$30,000	$63,588	$50,000	90	0.12
Newcastle, UT	$45,000	$156,437	$30,000	$245,737	$50,000	349	0.54
Bluffdale, UT	$45,000	$231,363	$30,000	$188,279	$50,000	267	0.90
Marysville, MT	$45,000	$2,128,979	$30,000	$154,665	$50,000	220	0.56
San Simon, AZ	$45,000	$2,090,105	$30,000	$123,146	$65,000	175	0.17
Cotton City, NM	$45,000	$137,940	$30,000	$245,746	$59,488	349	0.38
Govt. Camp, OR	$45,000	$830,345	$30,000	$18,828	$50,000	27	0.25
Vale, OR	$45,000	$83,391	$30,000	$131,809	$50,000	187	0.29
Lakeview, OR	$45,000	$189,354	$30,000	$219,898	$65,000	312	0.31
Klamath Falls, OR	$45,000	$335,216	$60,000	$285,702	$65,000	405	0.41
New Pine Creek, OR	$45,000	$460,071	$90,000	$543,829	$65,000	772	0.77
Breitenbush Hot Spg, OR	$45,000	$318,830	$30,000	$154,046	$50,000	219	0.77
Union, OR	$45,000	$511,000	$60,000	$278,397	$50,000	395	0.90
Star, ID	$45,000	$2,766,975	$30,000	$63,568	$61,360	90	0.10
Bridge, ID	$45,000	$479,250	$30,000	$24,471	$50,000	35	0.13
Swan Valley, ID	$45,000	$3,195,155	$30,000	$64,893	$50,000	92	0.15
Pyramid Lake, NV	$45,000	$783,750	$30,000	$147,203	$65,000	209	0.21

Table 6b. Costs and Pumping Power Associated with Well Field for the Series Configuration

Location	Explor. cost	Well cost	Well test & review	Pumps and Gathering system	Siting and Licensing	Pump Pwr (kW)	Fraction of Plant net
Beryl, UT	$45,000	$2,428,658	$30,000	$63,587	$50,000	90	0.34
Newcastle, UT	$45,000	$156,437	$30,000	$245,737	$50,000	349	0.68
Bluffdale, UT	$45,000	$231,363	$30,000	$188,279	$50,000	267	0.97
Marysville, MT	$45,000	$2,128,979	$30,000	$154,665	$50,000	220	0.68
San Simon, AZ	$45,000	$2,090,105	$30,000	$154,665	$50,000	220	0.39
Cotton City, NM	$45,000	$137,940	$30,000	$245,721	$50,000	349	0.55
Govt. Camp, OR	$45,000	$830,345	$30,000	$18,828	$50,000	27	0.46
Vale, OR	$45,000	$83,391	$30,000	$131,809	$50,000	187	0.49
Lakeview, OR	$45,000	$189,354	$30,000	$245,747	$50,000	349	0.51
Klamath Falls, OR	$45,000	$205,656	$60,000	$245,731	$50,000	349	0.57
New Pine Creek, OR	$45,000	$524,799	$90,000	$584,524	$65,000	830	0.83
Breitenbush Hot Spg, OR	$45,000	$318,830	$30,000	$154,046	$50,000	219	0.83
Union, OR	$45,000	$511,000	$60,000	$278,397	$50,000	395	0.97
Star, ID	$45,000	$2,766,975	$30,000	$62,949	$50,000	89	0.29
Bridge, ID	$45,000	$479,250	$30,000	$24,471	$50,000	35	0.35
Swan Valley, ID	$45,000	$3,195,155	$30,000	$62,949	$50,000	89	0.36
Pyramid Lake, NV	$45,000	$783,750	$30,000	$154,665	$50,000	220	0.43

If plants are considered where the geothermal fluid pump power does *not* affect the net plant output, then the COEs are shown in Figure 4 for the series configuration. In this figure are cost-shared COE results in which the total energy from the plant is not reduced by the energy required for geothermal fluid pumping, but the total life-cycle cost includes resource development capital and field O&M. Detailed COE information may be found in the Appendix. The cost-sharing scheme is a capital limit of $4,000,000 or 80%, whichever is lower. Field development capital includes expenses for exploration and testing. O&M costs are not covered by cost sharing. These results are based on specific power plant costs that are conservative, so will tend to be high for that reason. On the other hand, the COE does not reflect the drain on the power plant due to geothermal fluid pumping, which presumably will be budgeted against the direct use.

Figure 5 presents COE results for the situation in which the costs of resource development and maintenance are not considered. This is for the case in which a resource is already developed and the geothermal fluid needs only to be directed to a power plant, or in which the cost of resource development and the geothermal fluid pumping cost are attributed to a direct use. In this figure are cost-shared COE results in which the total energy from the plant is not reduced by the energy required for geothermal fluid pumping, and the total life-cycle cost excludes resource development capital and field O&M. The resulting COEs are for the power plant module only and represent the configuration with the lowest possible COEs.

Figure 6 presents a method of visualizing the COE results for the series case of Figure 5 and the no-direct-use, stand-alone flow case. These figures show a contour plot of COE as functions of flow rate and resource temperature. Much of the upper righthand corner of the plots should be disregarded since it is extrapolated information. They do not show the effect of well depth, which varies according to the resource. See the section on generic plants for COE contour plots at set depths.

For the case of the series configuration with resource development expense, but not pumping power, included, thirteen of the nineteen sites look promising with COEs less than 5¢/kWh. NREL learned that some of these sites may be particularly attractive for development. Newcastle is a good site due to having an interested owner and a direct use already installed. The greenhouse applications there would be able to expand to accommodate the additional geothermal fluid resource made available to the power plant. Lakeview also has good potential because it was previously the location for a number of small binary plants that were never used, because the owner did not have a power purchase agreement. The small plants were sold and moved elsewhere. Cotton City has the largest greenhouse installation in the country. New Pine Creek is a good candidate, too, because it also was the site of a binary plant in the 1980s, and the owners are looking for a means of using the resource. While it does not appear to have a current direct-use application installed, it is located in an agricultural area where crop drying or a greenhouse would fit in well. Zoning may also not be a problem[21].

If the plant module is considered with the exclusion of resource development expense and pumping power, all the sites look promising with cost-shared COEs less than 5¢/kWh. Most of the sites have COEs less than 5¢/kWh even without cost sharing.

The stand-alone configurations have the highest COE values as shown in Figure 7. Figure 8 is a contour plot of these results. Twelve sites have cost-shared COEs less than 5¢/kWh. Only one site has a COE lower than 5¢/kWh without cost sharing. Detailed COE data are in the Appendix.

The components of COE are shown in Tables 7a and 7b. Resource costs make up a significant fraction of some resources' COEs due to a high resource development cost and small plant. This is the case at Government Camp and Beryl. Resource development costs are low at Cotton City and Lakeview because the wells are relatively shallow at 440 ft. and 604 ft.

[21]Rafferty, Kevin, ibid.

Table 7a. Contributions to Total Cost-Shared COE Result for the Stand-alone Configuration (no collocated direct use)

		COE (¢/kWh) components for cost-shared results:			
Location	**Total COE**	**Plant Cap.**	**Field cap.**	**Plant O&M**	**Field O&M**
Beryl, UT	4.72	0.59	0.84	1.40	1.89
Newcastle, UT	6.25	1.55	0.38	3.64	0.68
Bluffdale, UT	39.34	8.49	3.89	19.93	7.04
Marysville, MT	15.11	1.70	2.92	4.00	6.49
San Simon, AZ	4.15	0.66	0.60	1.55	1.34
Cotton City, NM	4.00	1.04	0.19	2.43	0.34
Govt. Camp, OR	11.01	0.99	2.52	2.33	5.16
Vale, OR	3.42	0.90	0.16	2.12	0.24
Lakeview, OR	3.45	0.89	0.17	2.10	0.30
Klamath Falls, OR	4.43	1.08	0.28	2.55	0.52
New Pine Creek, OR	13.87	3.15	1.12	7.41	2.19
Breitenbush Hot Spg, OR	17.76	3.63	1.96	8.53	3.64
Union, OR	40.72	8.12	4.56	19.08	8.96
Star, ID	4.08	0.50	0.74	1.18	1.65
Bridge, ID	3.91	0.68	0.57	1.60	1.06
Swan Valley, ID	6.69	0.66	1.38	1.54	3.11
Pyramid Lake, NV	3.27	0.72	0.29	1.68	0.59

Table 7b. Contributions to Total Cost-Shared COE Result for the Series Configuration

		COE (¢/kWh) components for cost-shared results:			
Location	**Total COE**	**Plant Cap.**	**Field cap.**	**Plant O&M**	**Field O&M**
Beryl, UT	8.41	0.48	2.10	1.12	4.71
Newcastle, UT	2.72	0.63	0.22	1.48	0.39
Bluffdale, UT	3.82	0.79	0.42	1.85	0.76
Marysville, MT	7.45	0.70	1.58	1.65	3.52
San Simon, AZ	4.41	0.46	0.89	1.09	1.97
Cotton City, NM	2.44	0.59	0.17	1.38	0.30
Govt. Camp, OR	13.17	0.69	3.56	1.63	7.29
Vale, OR	2.42	0.58	0.19	1.36	0.28
Lakeview, OR	2.31	0.54	0.17	1.28	0.31
Klamath Falls, OR	2.58	0.60	0.21	1.40	0.37
New Pine Creek, OR	3.07	0.67	0.28	1.57	0.55
Breitenbush Hot Spg, OR	3.98	0.78	0.48	1.82	0.89
Union, OR	3.99	0.76	0.49	1.77	0.97
Star, ID	7.98	0.41	2.03	0.97	4.56
Bridge, ID	5.63	0.53	1.34	1.25	2.52
Swan Valley, ID	11.02	0.48	2.88	1.13	6.52
Pyramid Lake, NV	3.04	0.51	0.44	1.19	0.91

The cost-shared COEs can be compared to the local electricity price, as shown in Table 8. The series configuration is presented for the case in which the resource capital expense, but not the pumping power, is considered, and the case in which neither the resource capital expense nor the pumping power are considered.

Table 8. Comparison of COE and Local Electricity Prices for Power Plants that do *not* Need to Provide Additional Pumping Power. All values in (¢/kWh).

	COE, full cost share			Price	Local provider
Location	**Stand-alone**	**Series (inc. resrce)**	**Series (no resrce)**		
Beryl, UT	4.15	8.41	1.60	4.44	Dixie Escalante REA
Newcastle, UT	2.87	2.72	2.12	4.44	Dixie Escalante REA
Bluffdale, UT	3.93	3.82	2.64	4.73	Utah Power and Light
Marysville, MT	6.71	7.45	2.35	5.69	Montana Power Co.
San Simon, AZ	3.43	4.41	1.56	8.04	Sulphur Springs Valley Electric Coop
Cotton City, NM	2.48	2.44	1.96	10.40	Columbus Electric Coop
Govt. Camp, OR	8.30	13.17	2.32	4.86	Portland General Electric
Vale, OR	2.42	2.42	1.94	3.14	Idaho Power
Lakeview, OR	2.38	2.31	1.82	4.48	Pacific Power and Light
Klamath Falls, OR	2.63	2.58	1.99	4.48	Pacific Power and Light
New Pine Creek, OR	3.17	3.07	2.24	4.48	Pacific Power and Light
Breitenbush Hot Spg, OR	4.05	3.98	2.60	4.81	Consumers Power
Union, OR	4.07	3.99	2.53	5.48	Oregon Trail Electric Consumers Coop
Star, ID	3.69	7.98	1.39	3.14	Idaho Power
Bridge, ID	3.41	5.63	1.78	3.92	Raft River Coop
Swan Valley, ID	5.69	11.02	1.62	4.82	Lower Valley Power and Light
Pyramid Lake, NV	2.59	3.04	1.70	na	

If there is no direct use, and the power plant must be profitable on its own, the COE rises and makes the geothermal plant less competitive against the local provider. It should be kept in mind that the market for the power may be far from the plant, so a locally noncompetitive plant may be profitable when appropriate customers are found. The comparison between plant COE and local electricity prices is shown in Table 9.

Table 9. Comparison of COE and Local Electricity Prices for Power Plants that must Provide All Geothermal fluid Pumping Power. All values in (¢/kWh).

Location	COE, full cost share Stand-alone	Series (inc. resrc)	Price	Local provider
Beryl, UT	4.72	12.78	4.44	Dixie Escalante REA
Newcastle, UT	6.25	8.39	4.44	Dixie Escalante REA
Bluffdale, UT	39.34	145.20	4.73	Utah Power and Light
Marysville, MT	15.11	23.23	5.69	Montana Power Co.
San Simon, AZ	4.15	7.20	8.04	Sulphur Springs Valley Electric Coop
Cotton City, NM	4.00	5.41	10.40	Columbus Electric Coop
Govt. Camp, OR	11.01	24.42	4.86	Portland General Electric
Vale, OR	3.42	4.77	3.14	Idaho Power
Lakeview, OR	3.45	4.66	4.48	Pacific Power and Light
Klamath Falls, OR	4.43	6.05	4.48	Pacific Power and Light
New Pine Creek, OR	13.87	18.03	4.48	Pacific Power and Light
Breitenbush Hot Spg, OR	17.76	23.33	4.81	Consumers Power
Union, OR	40.72	151.55	5.48	Oregon Trail Electric Consumers Coop
Star, ID	4.08	11.23	3.14	Idaho Power
Bridge, ID	3.91	8.63	3.92	Raft River Coop
Swan Valley, ID	6.69	17.19	4.82	Lower Valley Power and Light
Pyramid Lake, NV	3.27	5.30	na	

3.3 Cost Results Based on ORMAT Specific Cost Estimate

ORMAT recommended using a fixed specific cost of $2,400 per kilowatt for all small plants. In most cases, this value is much lower than the Barber-Nichols costs, which were a function of plant size and resource temperature. Compared to the Barber-Nichols cost data, the ORMAT number is a very simple assumption; however, we have included its impact to provide a sense for the possible range of plant and COE costs that might be expected. The plant capital costs based on the ORMAT assumption are shown in Table 10.

Table 10. Plant Capital Cost Results Based on Simple Assumed Cost of $2,400/kW.

	Plant Size (kW)		Plant Capital Cost	
Location	**Stand-alone**	**Series**	**Stand-alone**	**Series**
Beryl, UT	748	264	$1,795,200	$633,168
Newcastle, UT	645	516	$1,547,778	$1,238,909
Bluffdale, UT	297	274	$712,578	$658,675
Marysville, MT	395	323	$947,160	$775,440
San Simon, AZ	1000	567	$2,400,000	$1,360,800
Cotton City, NM	915	634	$2,196,480	$1,521,940
Govt. Camp, OR	109	58	$260,840	$139,203
Vale, OR	635	379	$1,525,103	$910,276
Lakeview, OR	1000	690	$2,400,000	$1,655,949
Klamath Falls, OR	1000	607	$2,400,000	$1,456,800
New Pine Creek, OR	1000	1000	$2,400,000	$2,400,000
Breitenbush Hot Spg, OR	283	264	$679,830	$632,500
Union, OR	439	406	$1,053,648	$973,944
Star, ID	944	309	$2,265,600	$741,098
Bridge, ID	271	100	$649,344	$239,403
Swan Valley, ID	670	249	$1,608,927	$597,362
Pyramid Lake, NV	1000	516	$2,400,000	$1,237,981

The COE results for these plants, in which pumping power is *not* considered a drain on the plant, are shown in Figures 9 and 10 for the series configuration. Figure 9 contains cost-shared COE results in which the total energy from the plant is not reduced by the energy required for geothermal fluid pumping, but the total life-cycle cost includes resource development capital and field O&M. Figure 10 contains cost-shared COE results in which the total energy from the plant is not reduced by the energy required for geothermal fluid pumping and the total life-cycle cost excludes resource development capital and field O&M. The latter COE results thus represent the plant-only economics. Detailed COE data are in the Appendix. Thirteen sites with the series configuration that include resource costs have cost-shared COEs under 5¢/kWh. All of the sites with plant-only costs are under 5¢/kWh, with or without cost sharing. Klamath Falls should be excluded for reasons stated earlier. Breitenbush Hot Springs may not be a good candidate because of environmental impact concerns in the Cascades. Union's temperature is at the low extreme, and the resource also supplies a resort. Because the low output temperature from a Union binary plant and concerns about disrupting resort operations, this location is not a good candidate[22]. The Nevada site also has a low cost-shared COE. The Paiute Tribe owners of Pyramid Lake are known to be receptive to the idea of development of their resource. At one time, there was a direct use at Bluffdale, but there allegedly were problems with the wells and they were shut down. It is not known what the resource is like or how it is used at the other sites.

[22]Rafferty, Kevin, ibid.

In Table 11 these results are compared to local electricity prices. The geothermal price used in the comparison is the COE based on plant and field cost sharing. A number of series and stand-alone configuration sites have COEs lower than the local energy price.

Table 11. Plant COE Results Based on Simple Assumed Cost of $2,400/kW for Small Plants and Comparison to Local Electricity Prices for Power Plants that do *not* Need to Provide Additional Pumping Power. All values in (¢/kWh).

	COE, full cost share			Price	Local provider
Location	Stand-alone	Series (inc. rsrc)	Series (no rsrc)		
Beryl, UT	4.11	14.41	1.70	4.44	Dixie Escalante REA
Newcastle, UT	2.19	2.31	1.70	4.44	Dixie Escalante REA
Bluffdale, UT	2.80	2.89	1.70	4.73	Utah Power and Light
Marysville, MT	5.88	6.81	1.70	5.69	Montana Power Co.
San Simon, AZ	3.31	4.56	1.70	8.04	Sulphur Springs Valley Electric Coop
Cotton City, NM	2.03	2.18	1.70	10.40	Columbus Electric Coop
Govt. Camp, OR	7.50	12.56	1.70	4.86	Portland General Electric
Vale, OR	1.99	2.18	1.70	3.14	Idaho Power
Lakeview, OR	2.02	2.19	1.70	4.48	Pacific Power and Light
Klamath Falls, OR	2.18	2.29	1.70	4.48	Pacific Power and Light
New Pine Creek, OR	2.46	2.53	1.70	4.48	Pacific Power and Light
Breitenbush Hot Spg, OR	2.98	3.08	1.70	4.81	Consumers Power
Union, OR	3.06	3.17	1.70	5.48	Oregon Trail Electric Consumers Coop
Star, ID	3.86	8.30	1.70	3.14	Idaho Power
Bridge, ID	3.12	5.56	1.70	3.92	Raft River Coop
Swan Valley, ID	5.20	11.11	1.70	4.82	Lower Valley Power and Light
Pyramid Lake, NV	2.40	3.05	1.70	na	

If the plants are built with no direct use in mind, the pumping power becomes a significant drain on the plant, as seen before, and the COE rises, as shown in Table 12. COEs for the stand-alone configuration with pumping power are shown in Figure 11. If there is no direct use, then the stand-alone configuration will likely be the preferred scenario, unless the plant is built with the intention of using it with a direct use to be determined sometime far in the future. Detailed COE information is in the Appendix. A number of sites have plants in the stand-alone configuration with COEs lower than 5¢/kWh.

The comparisons to local electricity prices are shown below. A number of plants are competitive with local electricity prices.

Table 12. Plant COE Results Based on Simple Assumed Cost of $2,400/kW for Small Plants and Comparison to Local Electricity Prices for Power Plants that Must Provide All Geothermal fluid Pumping Power. All values in (¢/kWh).

	COE, full cost share		Price	Local provider
Location	Stand-alone	Series		
Beryl, UT	4.68	21.91	4.44	Dixie Escalante REA
Newcastle, UT	4.77	7.12	4.44	Dixie Escalante REA
Bluffdale, UT	27.98	109.62	4.73	Utah Power and Light
Marysville, MT	13.25	21.23	5.69	Montana Power Co.
San Simon, AZ	4.01	7.45	8.04	Sulphur Springs Valley Electric Coop
Cotton City, NM	3.29	4.83	10.40	Columbus Electric Coop
Govt. Camp, OR	9.94	23.29	4.86	Portland General Electric
Vale, OR	2.82	4.30	3.14	Idaho Power
Lakeview, OR	2.94	4.43	4.48	Pacific Power and Light
Klamath Falls, OR	3.67	5.38	4.48	Pacific Power and Light
New Pine Creek, OR	10.78	14.88	4.48	Pacific Power and Light
Breitenbush Hot Spg, OR	13.08	18.07	4.81	Consumers Power
Union, OR	30.57	120.25	5.48	Oregon Trail Electric Consumers Coop
Star, ID	4.27	11.68	3.14	Idaho Power
Bridge, ID	3.58	8.52	3.92	Raft River Coop
Swan Valley, ID	6.12	17.33	4.82	Lower Valley Power and Light
Pyramid Lake, NV	3.03	5.31	na	

4.0 Generic Cost Model

All of the analysis results reported have been for specific sites. It was important to use actual data for real locations in order to ensure that the results would be realistic and practical. In order to have results that are not site-specific, however, we also calculated generic economic results for a range of resource temperatures at different well flow rates and depths. Results for this type of analysis are shown in Figures 12, 13, 14, and 15. Each of these figures gives contour plots of COE as a function of flow rate for various resource temperatures. Each figure represents a different well depth: 500, 2000, and 8000 ft., except for the series configuration that does not include resource capital expense. That plot is applicable at any depth. The costs are calculated from Barber-Nichols small-scale power plant cost data. The COEs for the stand-alone configurations include full cost-sharing of 80% of total capital cost or $4 million (whichever is less), including exploration and well costs. For the series configuration, the plant module is fully cost shared. There are some extraneous contour lines plotted in the upper right corners of the plots. These should be ignored since they are products of the contour algorithm in an extrapolated region. No capital cost limit was imposed on these plants. The highest cost plants (including resource development costs) were for the 8000 foot deep resource, where the total capital cost was about $7 million.

These figures show that COE generally decreases with increasing resource temperature. The contours are not smooth everywhere due to the well costs being a stepwise function of total resource flow rate. COE also generally decreases with increasing geothermal fluid flow rate because plant size increases and specific cost ($/kW) drops due to economy of scale.

5.0 Conclusions

The economics of a small-scale power plant depends on the resource temperature, the available geothermal fluid flow rate, the required well depth and whether the parasitic pumping power can be attributed to a direct-use application.

Neglecting the small series option at Bridge, Idaho (100 kW) and the small plants at Government Camp, Oregon, plant sizes range from 249 kW to 1 MW (the upper limit imposed on this study). Total plant-only capital costs range from $566,000 to $3.4 million, and plant and field capital costs ranged from $1.4 million to $5 million (the upper limit imposed on this study). Costs are much higher when exploration and well costs are included. Costs of electricity, assuming an 80% or $4 million (whichever is lower) cost share of plant capital costs as well as exploration and well drilling and testing costs, fall under 5 ¢/kWh for more than half the plants. This compares to local electricity rates that are mostly in the range of 3 to 6 cents per kWh.

Even with an 80% cost share, costs of electricity are high because economies of scale work against small plants. This is especially true when exploration and drilling costs are necessary. These essentially fixed costs have a major impact on electricity costs for small plants. While it had been hoped in the early stages of this study that there might be existing wells available that would obviate exploration and drilling costs, it appears that this is not typically the case. And where existing wells are being used for direct-use applications, it is unlikely that extra geothermal fluid energy is available for power plant use. Thus in the real marketplace, economic justification for most of these plants would probably require combining the economics of the power plant with a new direct-use application.

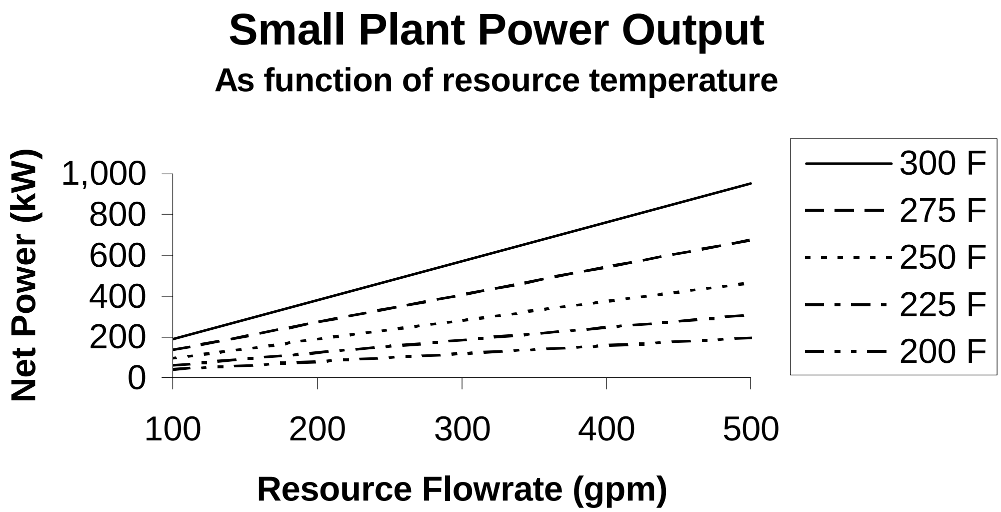

Figure 1. Net plant output as function of resource temperature and flowrate.

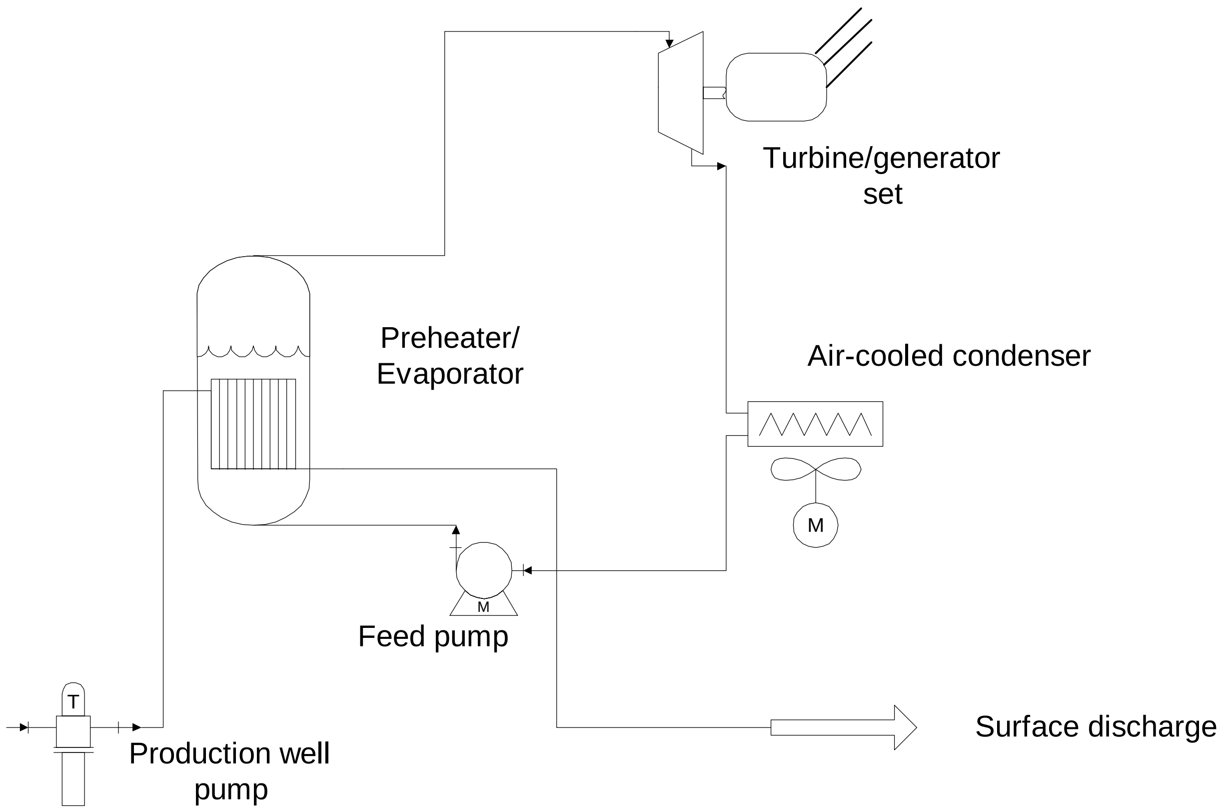

Figure 2. Rankine cycle used in this study.

Figure 3. Locations studied.

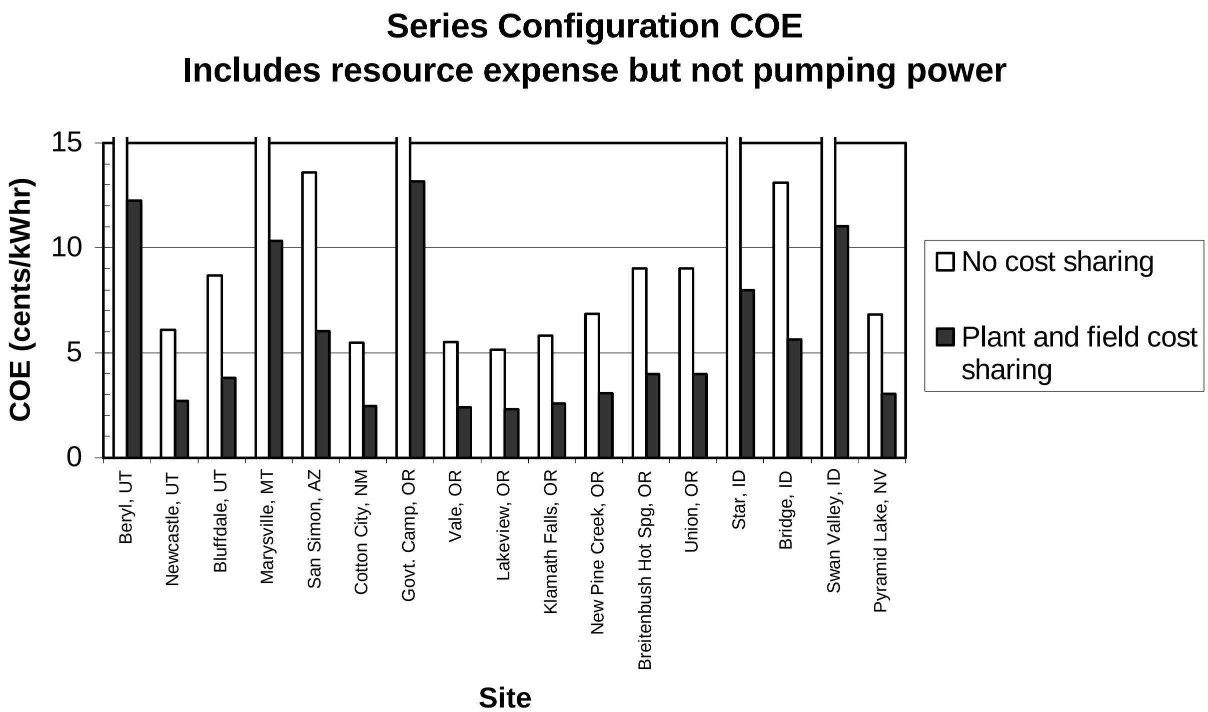

Figure 4. Series configuration COE with resource expense but no brine pump parasitics.

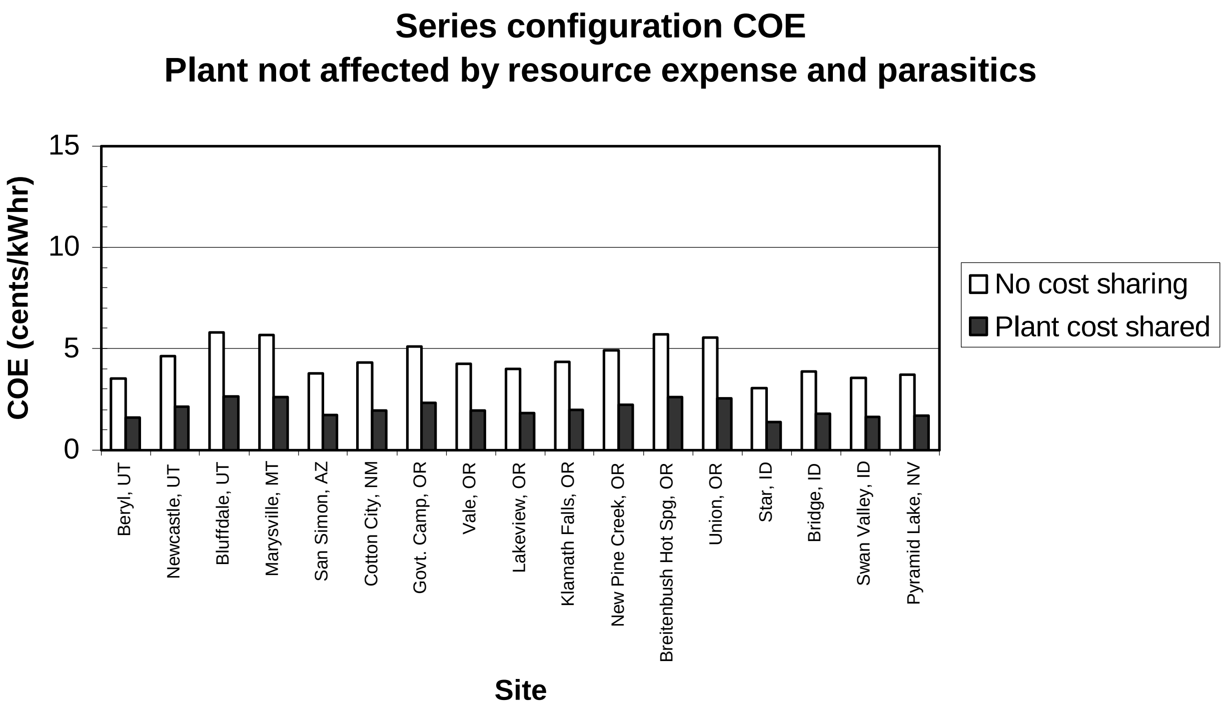

Figure 5. COE results for the series configuration in which there are no resource development expenses or pumping power parasitics.

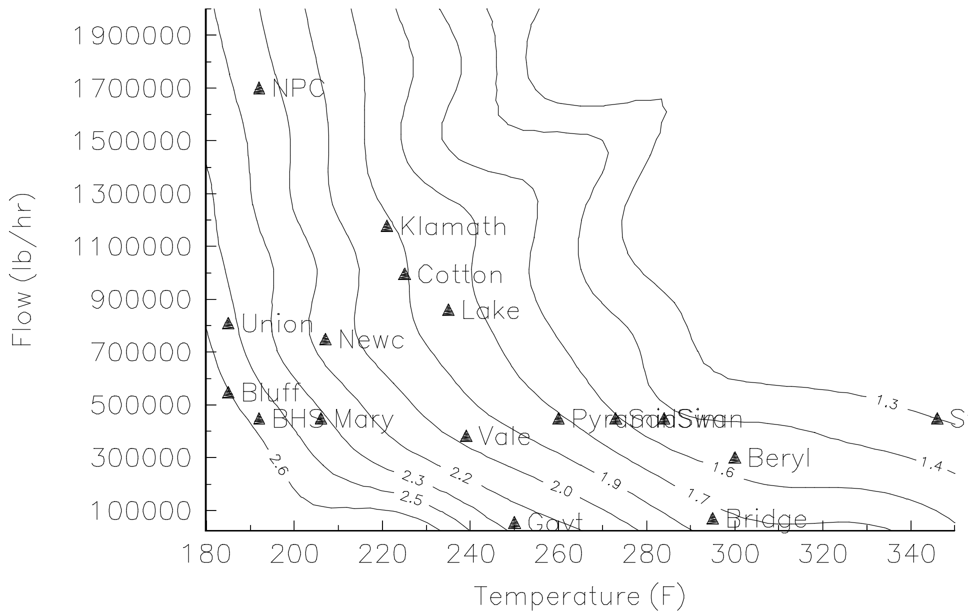

Figure 6. COE contours for the series flow configuration with no pumping power parasitic or resource capital expense, using Barber-Nichols specific cost.

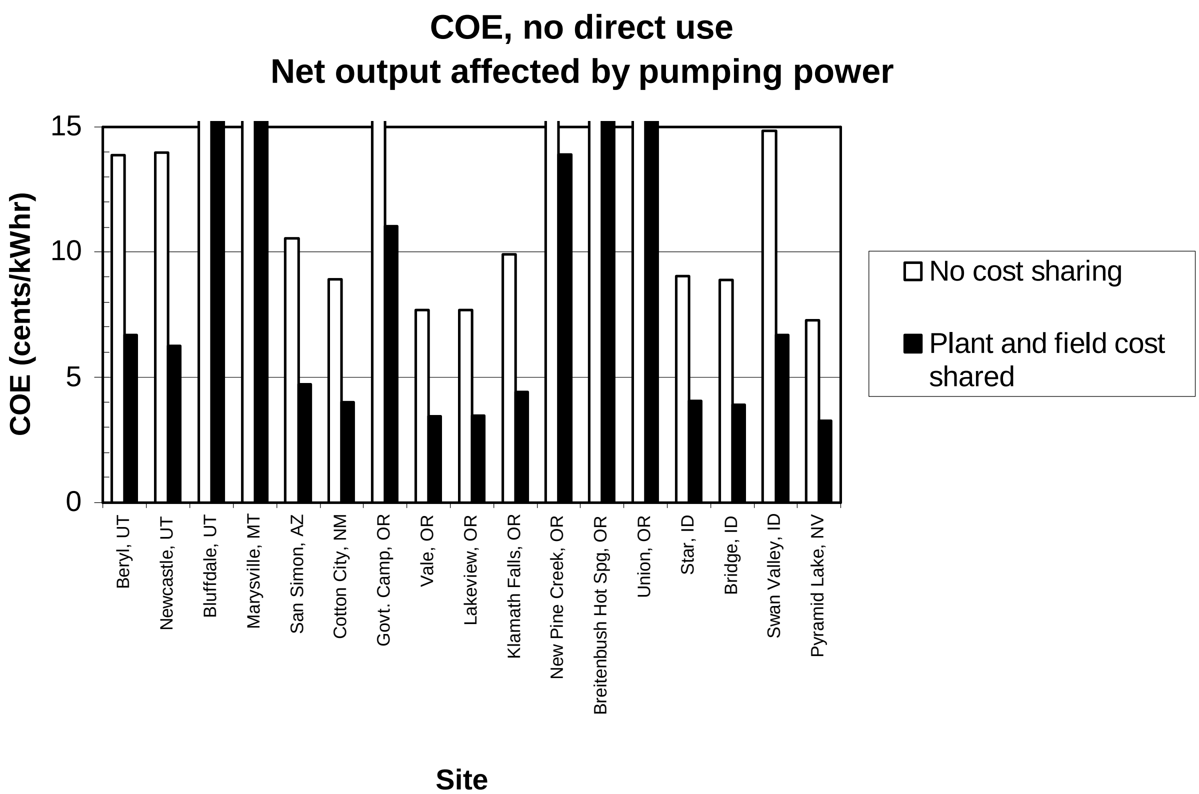

Figure 7. COE results for the case where the power plant is not tied into a direct use downstream.

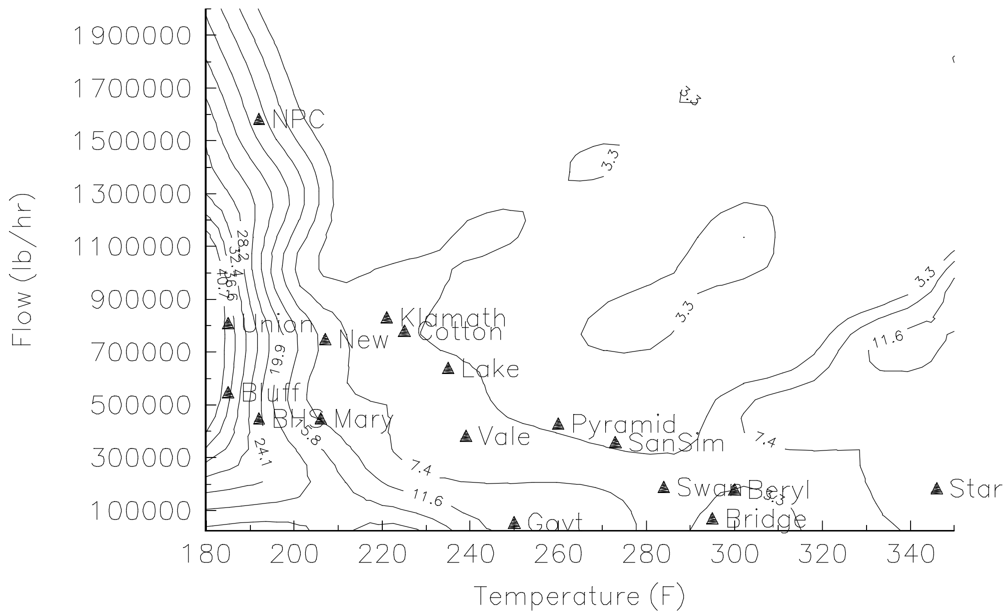

Figure 8. COE results for the stand-alone (no direct use) configuration, using Barber-Nichols specific costs.

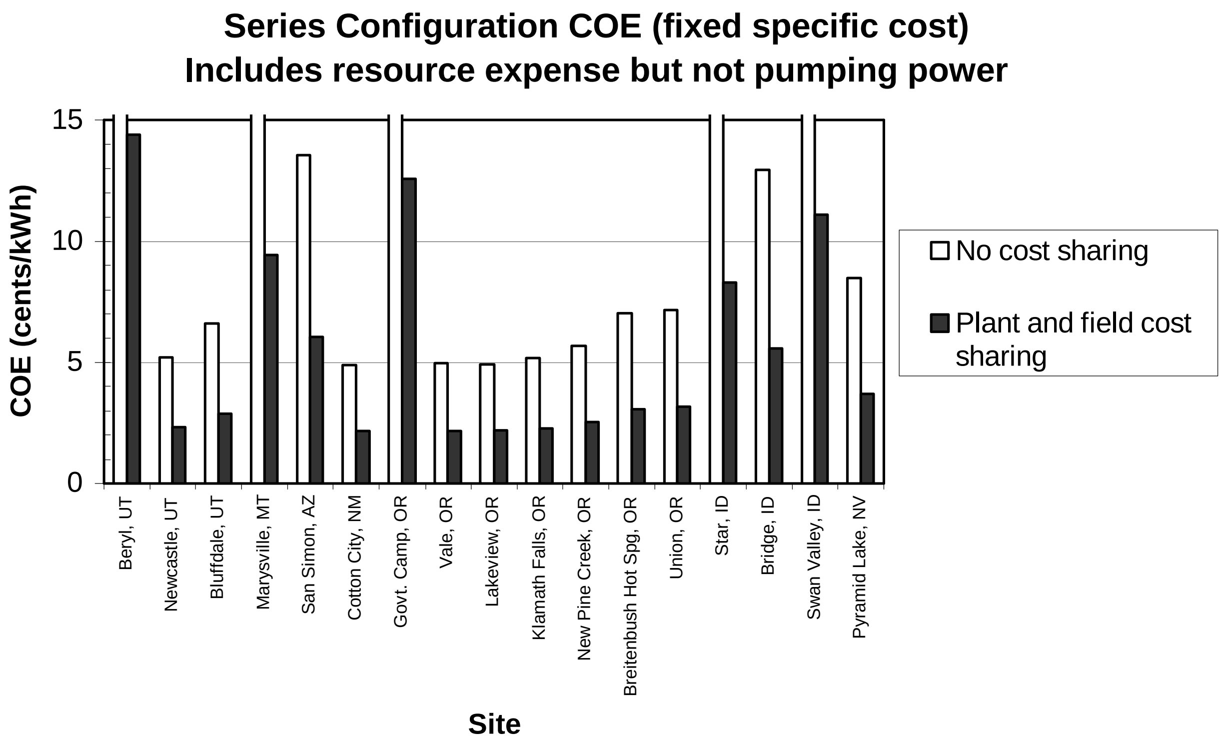

Figure 9. Series configuration COE at $2,400/kW, no pumping power but resource cost included.

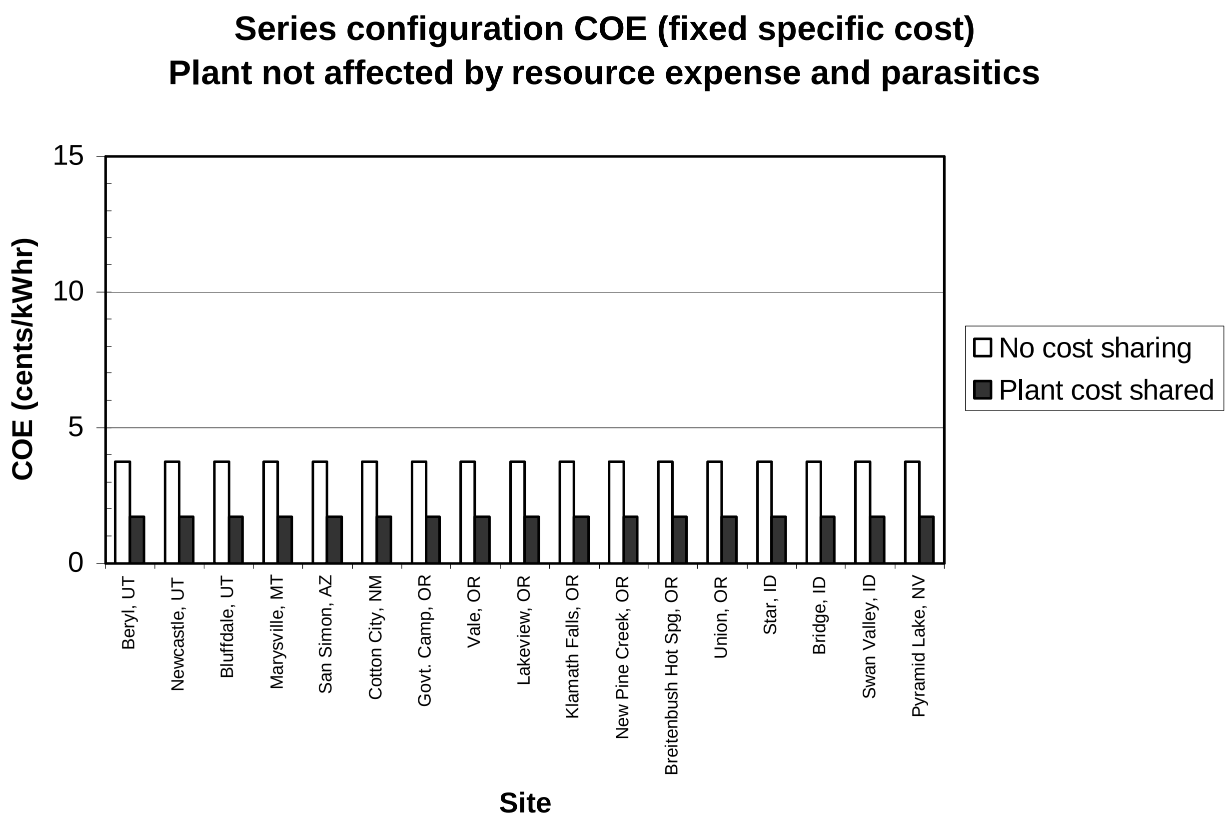

Figure 10. COE results for the series flow configuration at $2,400/kW, with no resource capital expense or geothermal fluid pumping power parasitics.

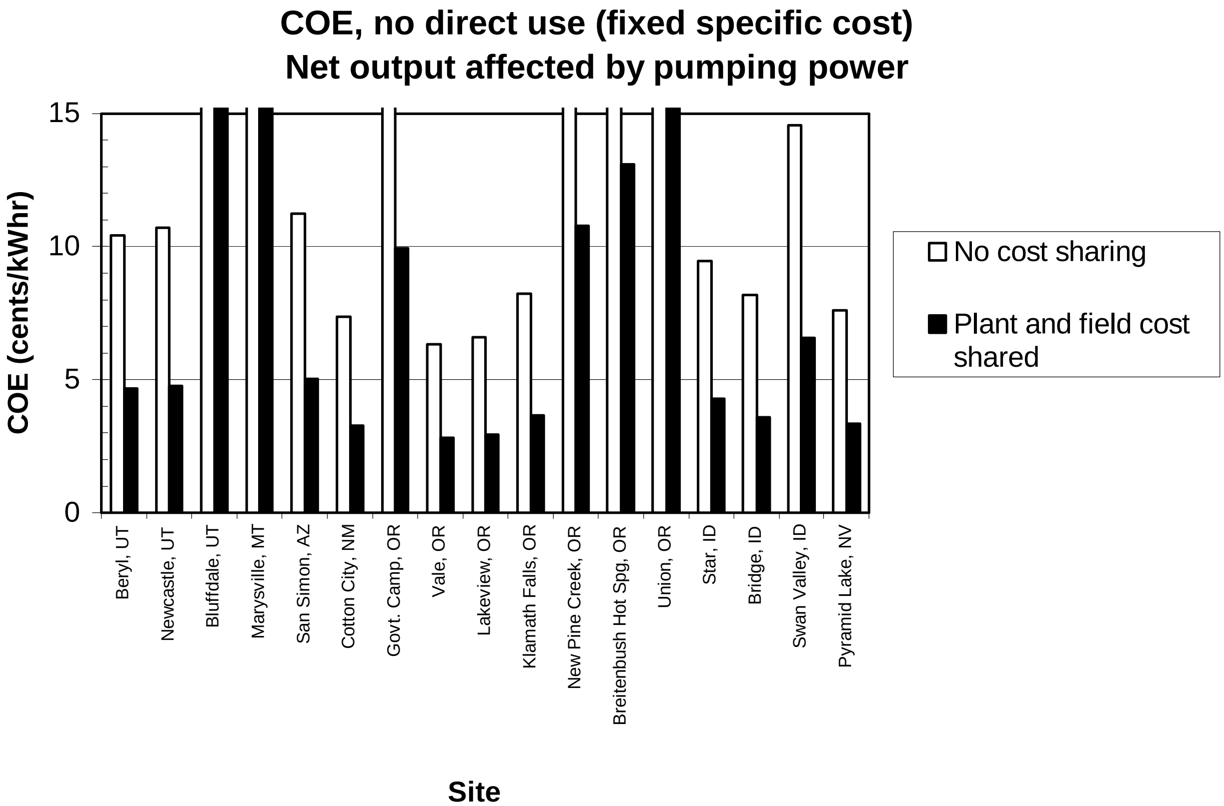

Figure 11. COE results for the stand-alone configuration (no direct use) at $2,400/kW.

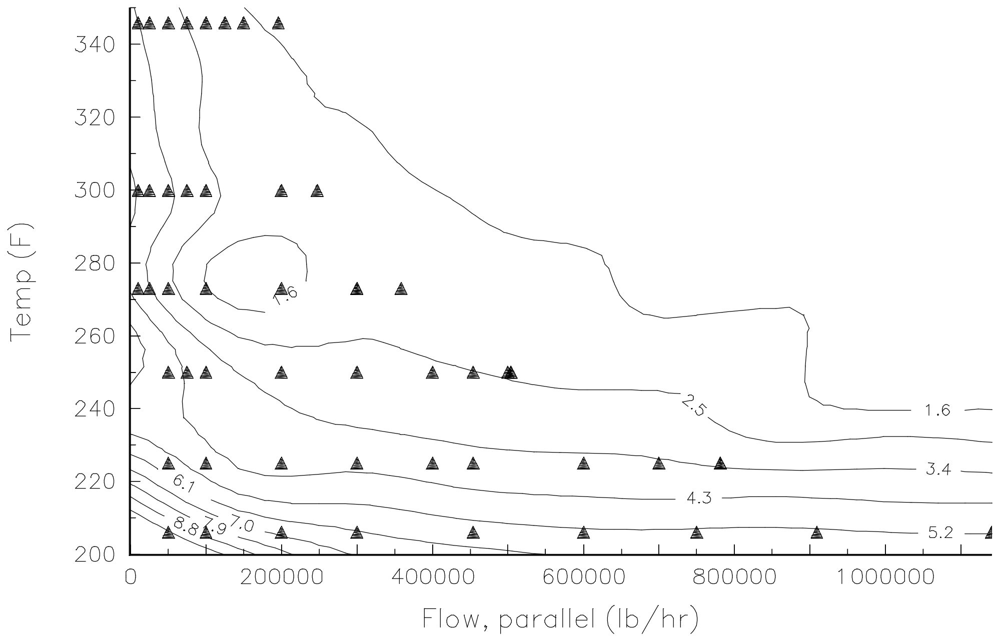

Figure 12. COE results for 500' depth, stand-alone, generic plants.

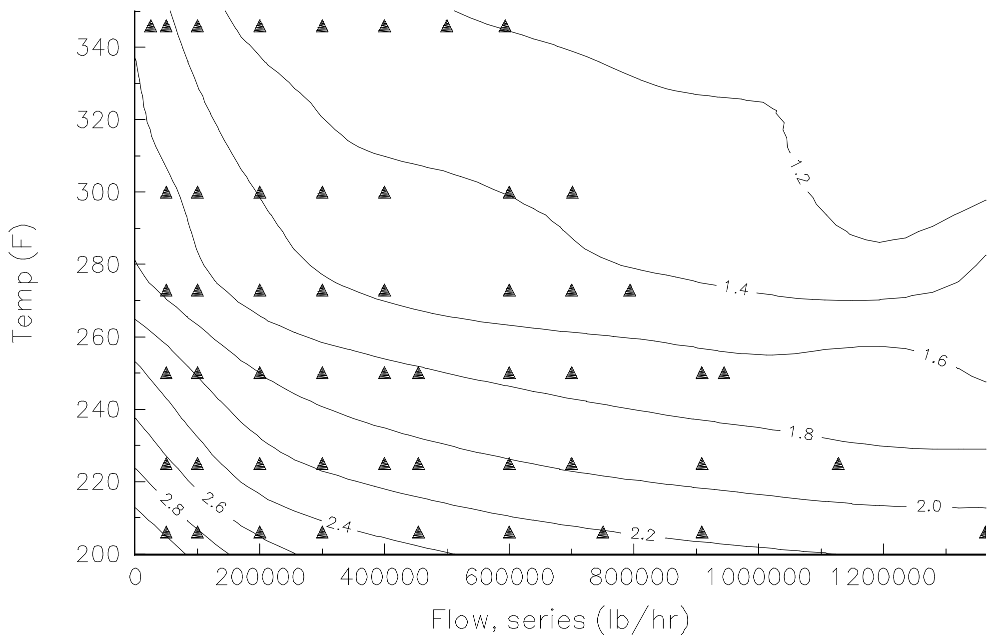

Figure 13. COE results for any depth, series flow (no resource expense/parasitics), generic plant, full cost sharing.

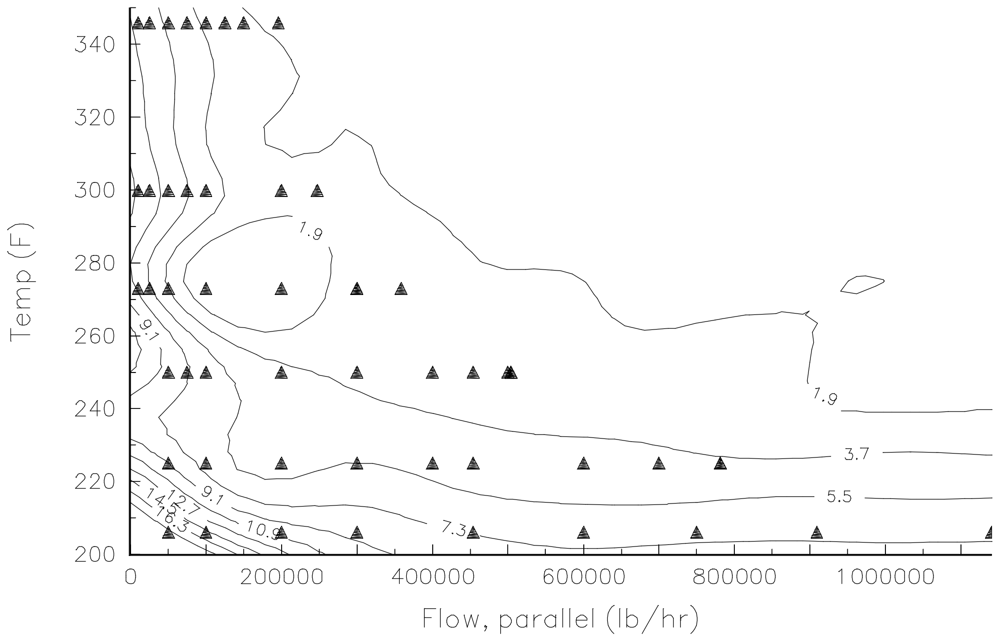

Figure 14. COE results for 2000' depth, stand-alone, generic plant, full cost sharing.

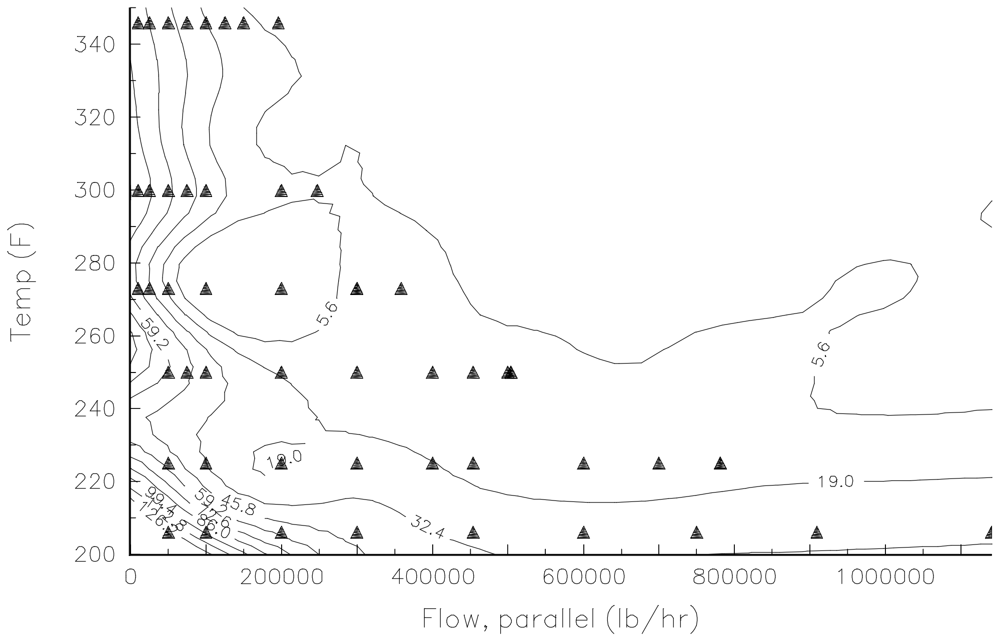

Figure 15. COE results for 8000' depth, stand-alone, generic plant, full cost sharing.

Appendix
Tabulated COE results

Table A1. COE results using Barber-Nichols specific costs. Plant economics exclude pump power.

Location	COE (¢/kWh) Stand-alone	Series	COE, plant cost share Stand-alone	Series	COE, plant and field cost share Stand-alone	Series
Beryl, UT	9.21	18.74	7.12	16.83	4.15	8.41
Newcastle, UT	6.41	6.11	3.25	3.31	2.87	2.72
Bluffdale, UT	8.88	8.66	5.11	5.16	3.93	3.82
Marysville, MT	14.90	16.57	11.55	13.46	6.71	7.45
San Simon, AZ	7.61	9.82	5.18	7.75	3.43	4.41
Cotton City, NM	5.52	5.46	2.67	2.86	2.48	2.44
Govt. Camp, OR	18.90	30.19	15.57	27.11	8.30	13.17
Vale, OR	5.42	5.50	2.59	2.92	2.42	2.42
Lakeview, OR	5.30	5.17	2.57	2.75	2.38	2.31
Klamath Falls, OR	5.88	5.80	3.02	3.16	2.63	2.58
New Pine Creek, OR	7.07	6.86	3.87	3.89	3.17	3.07
Breitenbush Hot Spg, OR	9.16	9.01	5.48	5.56	4.05	3.98
Union, OR	9.15	8.99	5.54	5.63	4.07	3.99
Star, ID	8.17	17.76	6.15	15.92	3.69	7.98
Bridge, ID	7.75	13.10	5.12	10.74	3.41	5.63
Swan Valley, ID	12.60	24.48	10.12	22.34	5.69	11.02
Pyramid Lake, NV	5.77	6.83	3.25	4.57	2.59	3.04

Table A2. COE results using Barber-Nichols specific costs. Plant economics exclude pump power and resource expense.

	COE (¢/kWh)		COE, plant cost share	
Location	**Stand-alone**	**Series**	**Stand-alone**	**Series**
Beryl, UT	3.84	3.51	1.75	1.60
Newcastle, UT	5.23	4.64	2.39	2.12
Bluffdale, UT	6.23	5.80	2.84	2.64
Marysville, MT	5.55	5.15	2.53	2.35
San Simon, AZ	4.01	3.41	1.83	1.56
Cotton City, NM	4.71	4.31	2.15	1.96
Govt. Camp, OR	5.50	5.09	2.51	2.32
Vale, OR	4.68	4.27	2.13	1.94
Lakeview, OR	4.51	3.99	2.06	1.82
Klamath Falls, OR	4.73	4.37	2.16	1.99
New Pine Creek, OR	5.29	4.92	2.41	2.24
Breitenbush Hot Spg, OR	6.09	5.71	2.77	2.60
Union, OR	5.97	5.55	2.72	2.53
Star, ID	3.35	3.04	1.53	1.39
Bridge, ID	4.36	3.90	1.99	1.78
Swan Valley, ID	4.10	3.55	1.87	1.62
Pyramid Lake, NV	4.17	3.73	1.90	1.70

Table A3. COE results using Barber-Nichols specific costs. **Plant economics include pump power.**

Location	COE (¢/kWh)		COE, plant cost share		COE, plant and field cost share	
	Stand-alone	Series	Stand-alone	Series	Stand-alone	Series
Beryl, UT	10.48	28.48	8.10	25.58	4.72	12.78
Newcastle, UT	13.96	18.85	7.76	11.06	6.25	8.39
Bluffdale, UT	88.85	328.94	54.91	209.12	39.34	145.20
Marysville, MT	33.59	51.70	26.78	42.96	15.11	23.23
San Simon, AZ	9.22	16.02	6.57	12.99	4.15	7.20
Cotton City, NM	8.93	12.14	4.78	6.93	4.00	5.41
Govt. Camp, OR	25.06	55.98	21.09	50.85	11.01	24.42
Vale, OR	7.68	10.85	4.07	6.27	3.42	4.77
Lakeview, OR	7.70	10.45	4.13	6.05	3.45	4.66
Klamath Falls, OR	9.90	13.64	5.56	8.05	4.43	6.05
New Pine Creek, OR	30.97	40.27	18.35	24.55	13.87	18.03
Breitenbush Hot Spg, OR	40.13	52.87	25.61	34.63	17.76	23.33
Union, OR	91.47	341.24	58.97	226.52	40.72	151.55
Star, ID	9.04	24.98	7.02	22.65	4.08	11.23
Bridge, ID	8.90	20.09	6.17	16.84	3.91	8.63
Swan Valley, ID	14.83	38.19	12.20	35.18	6.69	17.19
Pyramid Lake, NV	7.29	11.88	4.42	8.34	3.27	5.30

Table A4. COE results using the ORMAT single specific cost. Plant economics exclude pump power.

Location	COE (¢/kWh)		COE, plant cost share		COE, plant and field cost share	
	Stand-alone	Series	Stand-alone	Series	Stand-alone	Series
Beryl, UT	9.15	31.98	7.12	29.95	4.11	14.41
Newcastle, UT	4.92	5.21	2.66	2.95	2.19	2.31
Bluffdale, UT	6.39	6.61	4.13	4.34	2.80	2.89
Marysville, MT	13.10	15.17	10.83	12.90	5.88	6.81
San Simon, AZ	7.34	10.15	5.08	7.88	3.31	4.56
Cotton City, NM	4.55	4.89	2.29	2.63	2.03	2.18
Govt. Camp, OR	17.14	28.85	14.88	26.58	7.50	12.56
Vale, OR	4.48	4.97	2.21	2.71	1.99	2.18
Lakeview, OR	4.53	4.92	2.26	2.65	2.02	2.19
Klamath Falls, OR	4.89	5.17	2.63	2.91	2.18	2.29
New Pine Creek, OR	5.52	5.68	3.26	3.42	2.46	2.53
Breitenbush Hot Spg, OR	6.81	7.04	4.55	4.78	2.98	3.08
Union, OR	6.92	7.18	4.66	4.92	3.06	3.17
Star, ID	8.57	18.45	6.30	16.19	3.86	8.30
Bridge, ID	7.13	12.94	4.87	10.68	3.12	5.56
Swan Valley, ID	11.53	24.68	9.27	22.41	5.20	11.11
Pyramid Lake, NV	5.34	6.83	3.08	4.57	2.40	3.05

Table A5. COE results using the ORMAT single specific cost. Plant economics exclude pump power and resource expense.

Location	COE (¢/kWh) Stand-alone	Series	COE, plant cost share Stand-alone	Series
Beryl, UT	3.74	3.74	1.70	1.70
Newcastle, UT	3.74	3.74	1.70	1.70
Bluffdale, UT	3.74	3.74	1.70	1.70
Marysville, MT	3.74	3.74	1.70	1.70
San Simon, AZ	3.74	3.74	1.70	1.70
Cotton City, NM	3.74	3.74	1.70	1.70
Govt. Camp, OR	3.74	3.74	1.70	1.70
Vale, OR	3.74	3.74	1.70	1.70
Lakeview, OR	3.74	3.74	1.70	1.70
Klamath Falls, OR	3.74	3.74	1.70	1.70
New Pine Creek, OR	3.74	3.74	1.70	1.70
Breitenbush Hot Spg, OR	3.74	3.74	1.70	1.70
Union, OR	3.74	3.74	1.70	1.70
Star, ID	3.74	3.74	1.70	1.70
Bridge, ID	3.74	3.74	1.70	1.70
Swan Valley, ID	3.74	3.74	1.70	1.70
Pyramid Lake, NV	3.74	3.74	1.70	1.70

Table A6. COE results using the ORMAT single specific cost. Plant economics include pump power.

	COE (¢/kWh)		COE, plant cost share		COE, plant and field cost share	
Location	**Stand-alone**	**Series**	**Stand-alone**	**Series**	**Stand-alone**	**Series**
Beryl, UT	10.41	48.61	8.09	45.52	4.68	21.91
Newcastle, UT	10.71	16.07	6.28	9.79	4.77	7.12
Bluffdale, UT	63.91	250.86	43.54	173.54	27.98	109.62
Marysville, MT	29.51	47.31	24.92	40.96	13.25	21.23
San Simon, AZ	8.89	16.55	6.43	13.23	4.01	7.45
Cotton City, NM	7.35	10.87	4.06	6.35	3.29	4.83
Govt. Camp, OR	22.73	53.49	20.03	49.71	9.94	23.29
Vale, OR	6.35	9.82	3.46	5.80	2.82	4.30
Lakeview, OR	6.58	9.94	3.62	5.82	2.94	4.43
Klamath Falls, OR	8.22	12.15	4.80	7.37	3.67	5.38
New Pine Creek, OR	24.18	33.34	15.26	21.39	10.78	14.88
Breitenbush Hot Spg, OR	29.85	41.32	20.93	29.37	13.08	18.07
Union, OR	69.18	272.53	48.82	195.21	30.57	120.25
Star, ID	9.47	25.97	7.22	23.10	4.27	11.68
Bridge, ID	8.18	19.85	5.85	16.73	3.58	8.52
Swan Valley, ID	13.57	38.49	11.17	35.32	6.12	17.33
Pyramid Lake, NV	6.75	11.90	4.18	8.35	3.03	5.31